Recommendation to Pursue Membership in the Southwest Power Pool Regional Transmission Organization

Colorado River Storage Project and Loveland Area Projects

November 3, 2017

Western Area
Power Administration

Table of Contents

1. Introduction and recommendation

Western Area Power Administration (WAPA) has conducted collaborative analyses and extensive negotiations with seven other electricity providers along the Rocky Mountain Front Range[1] over the past four years. WAPA now recommends that the Colorado River Storage Project (CRSP) Management Center's Salt Lake City Area Integrated Projects and the Rocky Mountain (RM) region's Loveland Area Projects (LAP)[2] enter into final negotiations which, if successful, will result in CRSP and LAP joining the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) as transmission-owning members. WAPA will publish a *Federal Register* notice (FRN) to solicit customer feedback on this recommendation. This proposal follows the success of the transition of WAPA's Upper Great Plains (UGP) region to SPP membership in October 2015. It is projected that by expanding WAPA's participation in SPP to include CRSP and LAP, WAPA will secure near- and long-term reliability and economic benefits for customers in alignment with its commitment to providing power at the lowest possible rates consistent with sound business principles.

CRSP markets the output of Bureau of Reclamation-owned hydroelectric facilities of the Collbran Project, Rio Grande Project and the Colorado River Storage Project collectively known as the Salt Lake City Area Integrated Projects. The projects serve Arizona, Colorado, New Mexico, Utah and Wyoming with 1,816 megawatts of installed hydroelectric generation capacity and more than 2,323 miles of transmission line.

LAP markets the output of Bureau of Reclamation-owned hydroelectric facilities of the Fryingpan-Arkansas Project and the Pick-Sloan Missouri Basin Program—Western Division. The projects serve Colorado, Kansas, Nebraska and Wyoming with 830 megawatts of installed hydroelectric generation capacity and 3,360 miles of transmission line.

2. Context: The U.S. electric industry is evolving

The electricity industry in the U.S. is undergoing a fundamental shift that will increasingly affect bulk electric system operations, markets and planning. The combined impact of low natural gas prices, decentralization of natural gas and renewable generation, increases in variable generation resources, changes in consumer demand patterns and advancement of demand-side technologies are creating a significantly more dynamic system than what electricity providers have managed in the past.

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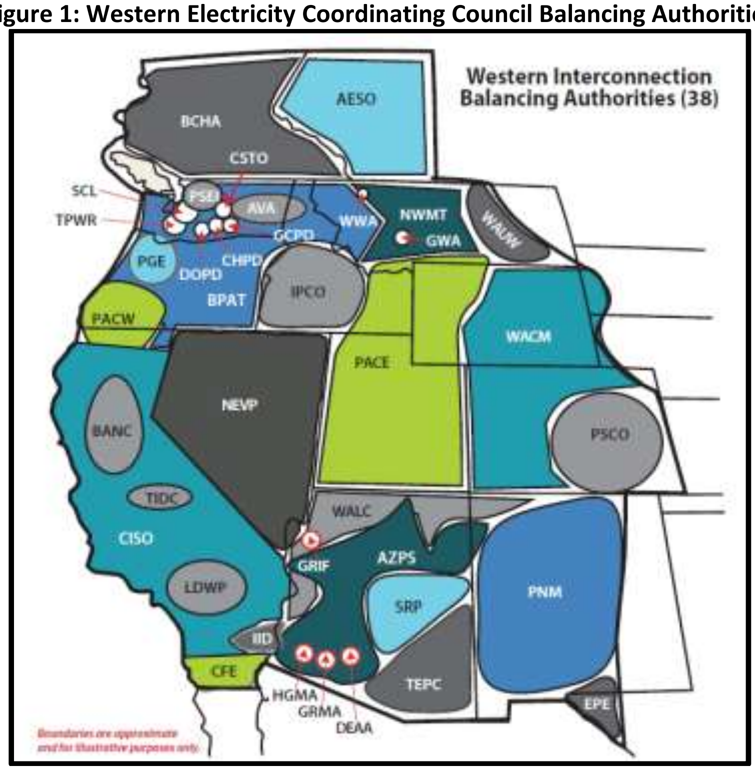
[1] The seven electricity providers created an informal collaboration in 2013 to develop strategies to adapt to a changing electricity industry. This group, referred to as the Mountain West Transmission Group, is discussed in detail in Section 4. The group includes Basin Electric Power Cooperative, Black Hills Energy, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission Association and Western Area Power Administration.

[2] While operational control of the LAP transmission system would be transferred to the SPP RTO in the event of membership, the RM region would be the official entity seeking membership. The LAP project is managed under RM.

Additionally, as the rules and regulations associated with operating the system have evolved over time, it has become an increasingly complex task to optimize the efficiency of the system while managing reliability. These shifts are affecting electricity system operations and economics at both the wholesale and retail level, motivating the expansion and creation of centralized markets for energy and ancillary services, altering power flows across the interconnection, increasing the interactions between the bulk electrical system (BES) and the distribution system and impacting both short- and long-term purchase power transactions.

The majority of the Western Interconnection[3] is characterized by small Balancing Authorities (BAs), hourly schedules, bilateral energy transactions and contract path transmission arrangements. As a result of the shifts in the electricity industry, the way the system was historically operated is becoming untenable and there is an increasing need for wide-area situational awareness and control, access to geographically and operationally diverse generation resources, flow-based transmission operations, sub-hourly operations and fast-dispatch centralized markets. These are features ubiquitous in the RTOs that encompass large geographical areas in the Midwest, the Northeast, Texas and California. RTOs have the ability to dispatch and rebalance the system in sub-hourly and near-real-time increments using algorithms designed to co-optimize system reliability and economic performance.

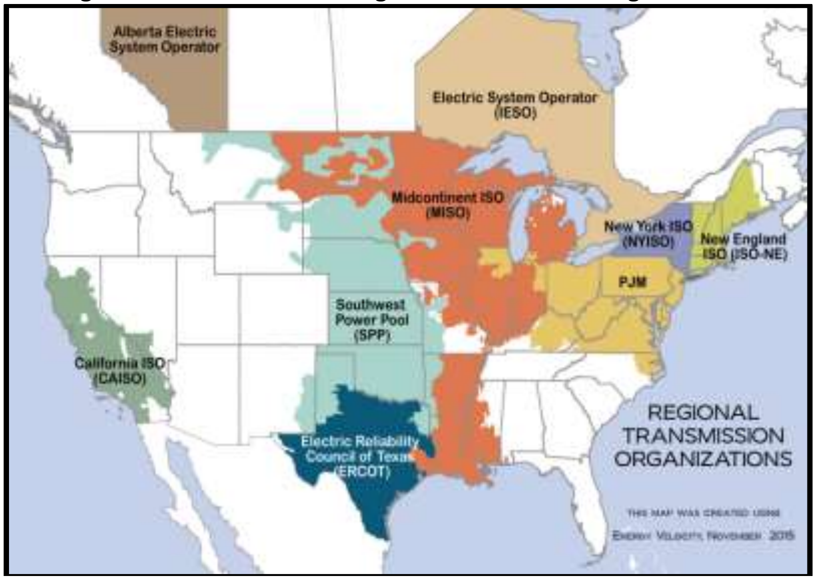
Figure 1: Western Electricity Coordinating Council Balancing Authorities



Graphic credit: Western Electricity Coordinating Council

[3] This does not include the Alberta Independent System Operator or the California Independent System Operator.

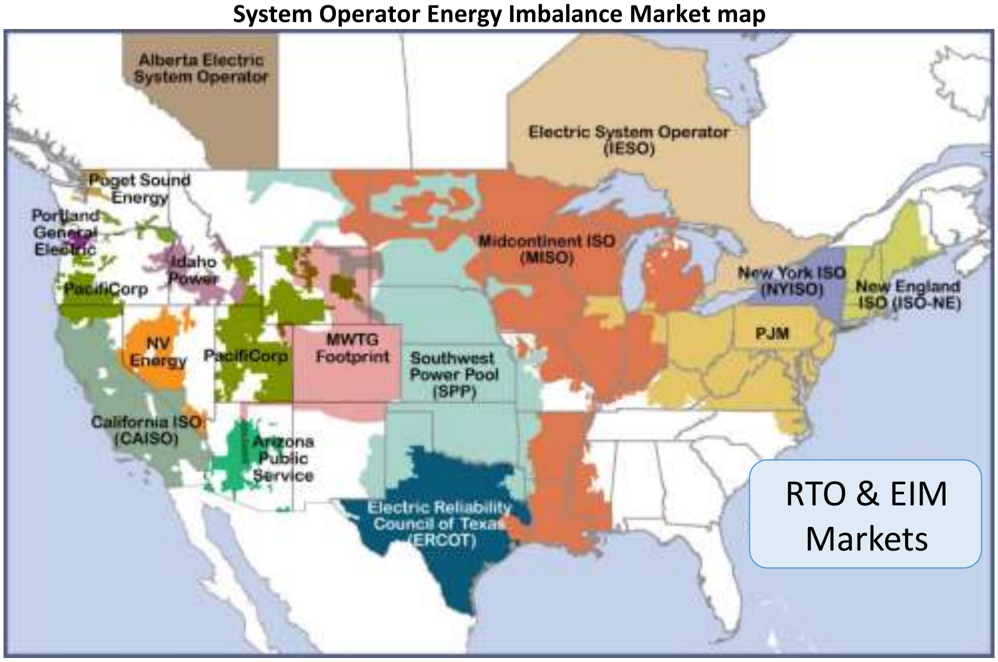
Figure 2: North American Regional Transmission Organizations



Graphic credit: Federal Energy Regulatory Commission

As a result, electricity providers in the West are evaluating risks associated with the status quo relative to the costs and benefits of RTO membership or variants of centralized operations and markets. For WAPA, CRSP and LAP in particular, RTO participation has the potential to provide benefits to customers, preserve reliability and hedge against risks associated with ongoing changes in the electricity industry.

Figure 3: Regional Transmission Organizations, Mountain West Transmission Group and California Independent System Operator Energy Imbalance Market map



Graphic credit: Compilation by Mountain West of the Federal Energy Regulatory Commission RTO map, the Mountain West Footprint, and the California Independent System Operator Energy Imbalance Market map

Relatively near-term action is critical for WAPA to retain its ability to define its own future, protect its negotiating power and avoid having its options constrained by the actions of other entities. UGP joined SPP along with Basin Electric Power Cooperative and Heartland Consumers Power District in 2015 in response to a reduction in bilateral trading partners due to other entities joining SPP and an interest in further leveraging coordinated transmission planning. The benefits to date of UGP's participation in SPP have exceeded expectations.

3. Implications of industry change for CRSP and LAP

CRSP and LAP are significantly affected by the infrastructure and institutional changes discussed in section two because:

- CRSP and LAP are significant purchasers of wholesale electricity, and both per-megawatt unit costs of energy and price volatility are of concern.
- Development of markets around CRSP and LAP will likely reduce access to bilateral trading partners, putting CRSP and LAP at risk of increasing supply costs and inability to sell excess generation.
- As generation declines from coal and nuclear units, the location and type of replacement generation will change the path ratings for transmission corridors that CRSP and LAP use to deliver firm electric power to WAPA customers.
- CRSP and LAP transmission sales will similarly be affected by changes in power flows that increase or decrease available transfer capability (ATC) on some lines.
- WAPA's Western Area Colorado Missouri (WACM) BA will be required to accommodate the changes in power flows and ancillary service needs that will result from the changes in the generation mix.

4. The Mountain West Transmission Group

The Mountain West Transmission Group (Mountain West) is a collaboration of electricity service providers that are working to develop strategies to adapt to the changing electric industry. The group was formed in early 2013 to evaluate an array of options ranging from a common transmission tariff to RTO membership. Based on the results of evaluations performed to date, Mountain West is focusing its attention on full membership in an existing RTO.

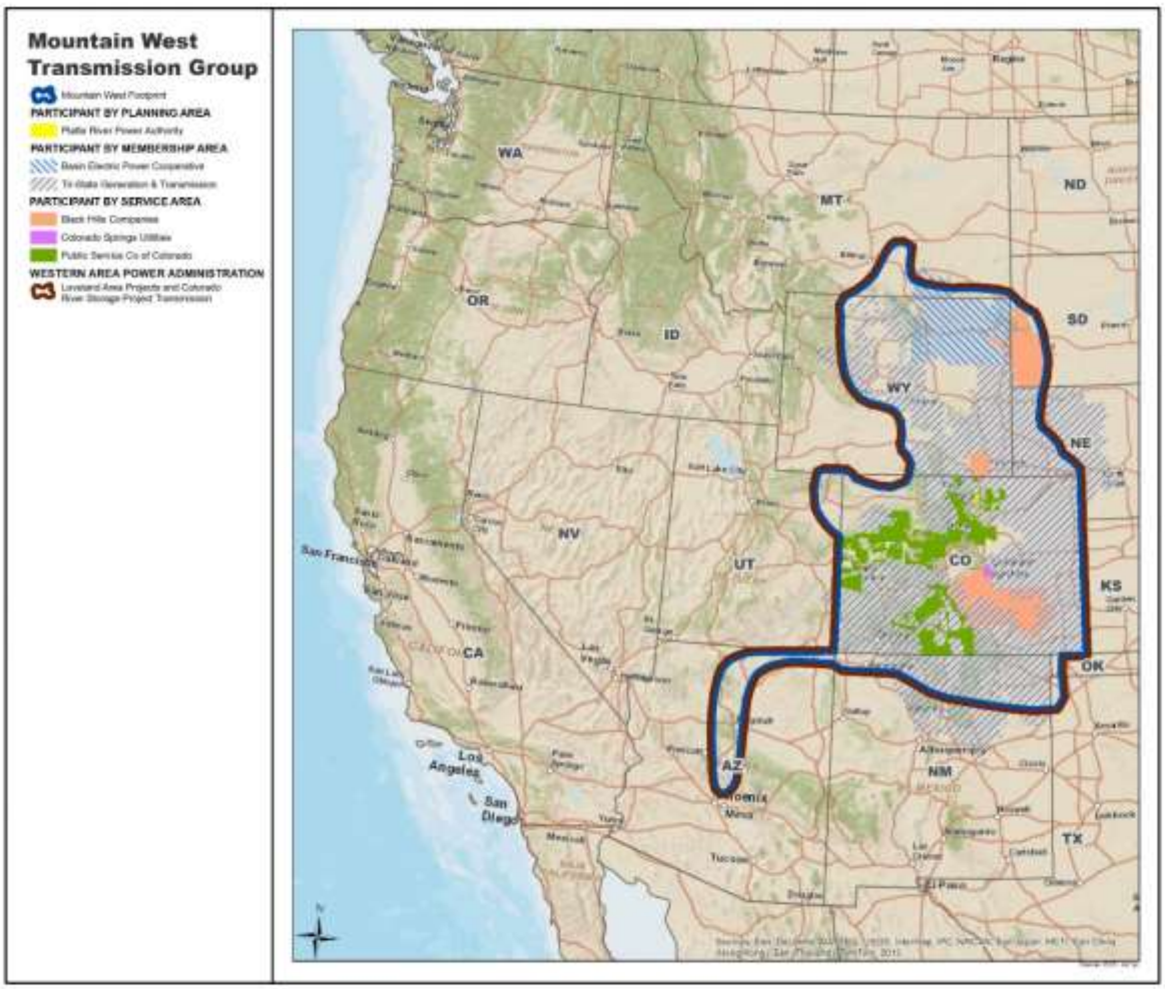
Mountain West includes two investor-owned utilities, two municipal electricity providers, two generation and transmission cooperatives and two federal power marketing administration projects. The Mountain West participants are a subset of the WestConnect planning region and are members of the Colorado Coordinated Planning Group. Current participants are listed below, and other electricity providers are expected to join after initial implementation.

- Basin Electric Power Cooperative (BEPC)
- Black Hills Energy (BHE):
    - Black Hills Power (BHP)

- Black Hills Colorado Electric Utility Company (BHCE)
  - Cheyenne Light Fuel & Power Company (Cheyenne)
- Colorado Springs Utilities (CSU)
- Platte River Power Authority (PRPA)
- Public Service Company of Colorado (PSCO)
- Tri-State Generation and Transmission Association (Tri-State)
- Western Area Power Administration (WAPA):
  - CRSP
  - LAP

The Mountain West service territory is shown in Figure 4. It includes the WACM Balancing Authority Area (BAA) and the PSCO BAA.

Figure 4: Mountain West Transmission Group service territory



5. Options considered

As part of the process of developing the recommendation for CRSP and LAP to join the SPP RTO, the projects collaborated with the other electricity providers in Mountain West to evaluate a common transmission tariff or RTO membership, which includes both a common tariff and a wholesale market. Based on the results of the evaluations, the group decided in late 2016 and formally announced in early 2017 that it would focus its attention on full RTO participation.

5.1 Status quo/no action

The electricity-generating portfolio in the U.S. is undergoing a fundamental shift due to the combined impact of low natural gas prices, reduced demand growth, decades of progressively more stringent environmental regulations, tax incentives for renewable energy and ongoing regulatory uncertainty. Rapid foundational changes create long-term risk for WAPA and customers, and accelerate the need for WAPA to implement strategies that enable the organization to be resilient and flexible in a dynamic future while maintaining its ability to meet statutory obligations to its customers and ensuring the reliability of its system.

For CRSP and LAP, market expansion has had minimal operational or economic impacts to date. This would change as the California Independent System Operator (CAISO) energy imbalance market[4] footprint expands, however any impacts would be isolated to real-time operations and real-time merchant activities. If a full RTO were created in the West and CAISO expands its Independent System Operator (ISO) footprint beyond California, significant operational and economic impacts are expected for entities that remain outside of an RTO. These impacts are listed below:

- Adhering to status quo/no action would prevent CRSP and LAP from receiving the benefits of more efficient transmission planning and integration.
- There would likely be a loss of significant negotiated benefits such as the federal service exemption (FSE),[5] specific zonal transmission constructs and loss of cost mitigation among the participants.
- The loss of bilateral trading partners would likely increase purchase power prices and reduce surplus sale prices as fewer remaining bilateral trading entities would potentially have increases in market power and negotiating leverage with the implementation of new markets, or further energy imbalance market (EIM) expansion in the West. Hurdle

[4] The CAISO EIM, launched in 2014, has six participating balancing authorities. The EIM is fundamentally a real-time only energy market, and is projected to include two-thirds of the net energy for load in the Western Interconnection by 2021.

[5] The FSE refers to exemptions from the marginal congestion cost component and marginal loss cost component for federal energy deliveries and certain transmission cost allocation charges. Although UGP was able to negotiate an FSE in SPP, the exemption may not occur in other Regional Transmission Organizations. SPP currently has the FSE in their tariff and it only needs to be expanded to include CRSP and LAP.

rates[6] for purchases directly from an RTO market from outside of the RTO footprint would create upward pressure on purchase power costs that otherwise would not be incurred if CRSP and LAP were to join the SPP RTO.

- CRSP and LAP transact across the West and incur the economic impacts of pancaked transmission rates.[7] Joining the SPP RTO is an opportunity to reduce these costs and benefit from the resource optimization provided by a market with one transmission rate and least cost dispatch.
- There is a risk that development of RTOs, other than SPP, around WAPA's CRSP and LAP service territories would have cultural, governance or market characteristics that would not be in alignment with the organizational objectives of WAPA and its customers.
- The generation mix in the West is changing and creating challenges for system operations and reliability. The current paradigm of multiple small BAs such as the WACM BAA creates challenges to accommodate variable generation on the system. Each BA has limited resources for regulation and reserves required to follow both variable load and variable generation. RTOs leverage generation resources across large geographical footprints to accommodate large amounts of variable generation and maintain reliability.

Since the early 2000s, WAPA has actively been monitoring and evaluating market-based activities across the Western U.S. and has determined that a "status quo/no action" approach for CRSP and LAP now creates an unacceptably high level of risk.

WAPA has taken proactive steps to evaluate and implement strategies that enable the organization to be resilient and flexible in a dynamic future while maintaining its statutory obligations and the reliability of its system. For CRSP and LAP, this includes entering into final negotiations which, if successful, will result in CRSP and LAP joining the SPP RTO as transmission-owning members.

5.2 Common tariff option

5.2.1 Common transmission tariff

Mountain West participants have their own transmission tariffs. These tariffs set the terms and rates for providing transmission service to all transmission customers. This includes selling transmission service, performing transmission studies, interconnecting new generators and many other wholesale electricity functions. A common transmission tariff would be a single tariff covering multiple transmission zones. Under a zonal design, the customers pay the transmission rate for the zone in which their loads are located and do not incur additional transmission charges for transporting energy across other zones within the RTO. Zonal rate design is used by the majority of RTOs in the U.S.

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[6] Hurdle rates are charges to export energy out of an RTO.

[7] Rate pancaking occurs when a transmission customer is charged separate access charges for each utility service territory the customer's contract path crosses.

5.2.2 Benefits of a common tariff

There are nine transmission tariffs[8] in the Mountain West footprint. By combining the nine tariffs into one, the Mountain West participants will collectively:

- Make more efficient use of the existing transmission system by transitioning away from contract-path to flow-based transmission sales. This allows more optimal utilization of available transfer capacity (ATC).
- Eliminate transmission rate pancaking for grid use. "Rate pancaking" is a term used to describe the addition of delivery charges that occurs when wheeling energy across multiple transmission systems. Rate pancaking impedes the use of least-cost generation resources by increasing transaction costs.
- Support improved transmission planning and interconnection processes by increasing coordination between and across the systems. This would help to avoid duplication of facility investments and will create additional siting opportunities for new resources.

5.3 RTO option

An RTO:

- Utilizes a common tariff to manage the operation of the transmission systems and generation resources of multiple electricity providers to optimize the utilization of their assets for the benefit of the entire RTO footprint.
- Maintains a wide-area view and real-time situational awareness of the entire footprint to monitor and manage the reliability of the system.
- Serves as the centralized operator for a Day-2 market for auction-based electricity products.[9]
- Provides market monitoring oversight.
- Facilitates transmission planning across multiple transmission systems and states.
- Performs ongoing assessments to ensure that generation and transmission resource adequacy are in alignment with reliability, economic and public policy requirements.

5.3.1 Considering an RTO

As the rules and regulations associated with operating the interconnected transmission system have evolved over time, it has become an increasingly complex task to optimize the efficiency of the system while managing reliability. An RTO is able to use its wide-area view, real-time

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[8] These include Basin Electric Power Cooperative, Black Hills Colorado Electric Utility Company, Black Hills Power, Cheyenne Light Fuel and Power, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission and WAPA.

[9] These products include varying combinations of energy, capacity and ancillary services, such as day-ahead unit commitment, reliability unit commitment and real-time dispatch.

situational awareness and ability to optimize market operations across a broader footprint to enhance coordination, increase reliability and create greater efficiency.

5.3.2 Benefits of RTO market participation

Participation in an RTO is expected to provide value for WAPA and its customers. The Mid-Continent Independent System Operator (MISO)[10], SPP[11] and PJM Interconnection (PJM)[12] have recently released statements regarding the value their RTOs bring to their respective regions. An RTO's regional operational control permits more efficient grid use. This results in daily operational cost savings. This also creates savings over time through reduced regional infrastructure investments in response to growth in demand or changes in energy production resources.

As examples:

- MISO reports that from 2007 through 2016, the RTO generated $17.5 billion in net benefits.
- PJM estimates annual net benefits of $2.1 to $2.8 billion.
- SPP reports that their integrated marketplace has saved over $1 billion since 2014.

Utilities participating in an RTO have benefited from more efficient unit commitment and dispatch of generation and improved operating reserve procurement.

5.4 LAP joining SPP first, CRSP at a later date

The option of having LAP join SPP with CRSP to follow at a later date was evaluated. WAPA believes having both projects join at the same time provides better overall results for both projects for the reasons identified in the remainder of this section.

5.4.1 RC services, outage coordination and maintenance

The CRSP and LAP systems reside within the WACM BAA and have the same contracted reliability coordinator (RC) services. The Loveland and Phoenix control centers back one another up in emergencies, allowing either to operate the CRSP and LAP systems when necessary.

5.4.2 Path operations, parallel transmission, unscheduled flow mitigation

LAP manages the path operations for the major congested elements in both the CRSP and LAP systems. If LAP were to join an RTO and CRSP were not to, congestion management for the LAP

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[10] https://www.misoenergy.org/WhatWeDo/ValueProposition/Pages/ValueProposition.aspx
[11] https://www.spp.org/about-us/newsroom/total-savings-from-spp-s-markets-cross-the-1-billion-mark/
[12] http://www.pjm.com/about-pjm/value-proposition.aspx

portion of the system would be performed through the market via a combination of security-constrained unit commitment, security-constrained economic dispatch, day-ahead simultaneous feasibility tests and real-time reliability unit commitment.

In the case of the CRSP system, there would be parallel elements with Mountain West members. The path operations desk would have to remain to ensure that CRSP elements didn't overload and to coordinate operations with the RTO. Operating these elements in a bilateral environment would be less reliable and less efficient than a single operator utilizing a flow-based methodology.

Additionally, CRSP has two out of the four qualified constrained paths in the Western Electricity Coordinating Council (WECC). Operational complexities regarding path operations and the interface with the Unscheduled Flow Mitigation Plan (UFMP) would need to be identified and reduced. CRSP is paid to operate the Shiprock and Waterflow phase shifters for the WECC UFMP process. With an RTO this would still be required, but CRSP not being part of the RTO would create a more complex coordination process between the security constrained economic dispatch, UFMP and regular operations. This would create reliability risks that would affect the entire interconnection.

5.4.3 Balancing authority services

CRSP and LAP are both in WACM. If LAP were to join an RTO, CRSP's options for BA service would be to join the RTO BA as a BA participant only, to move entirely into the Western Area Lower Colorado (WALC) BAA or to maintain the WACM BAA to operate the CRSP system.

5.4.4 CRSP as a balancing authority participant only

The RTO would not allow CRSP to be a BA services-only participant. CRSP would not be operated as part of the market but rather as a sub-BA with generation and ancillary services valued and traded in the bilateral market. The cost and complexity of supporting a standalone BA within the RTO market would be outside the current scope of the RTO functionality, and the value proposition for the RTO would likely be minimal to negative. More importantly, this type of operational arrangement would also require the RTO to accept additional reliability responsibilities, which it would be unlikely to do.

There would more than likely be additional metering requirements to ensure that the market model solves correctly with a bilateral sub-BA component. Each interface between the BA and sub-BA, as well as the far end of the CRSP system, which would be the border of the SPP BA, would have to be considered to determine unique issues to be addressed. It is inevitable that issues would exist.

5.4.5 CRSP moving entirely into the WALC BA or maintaining the WACM BA to operate the CRSP system

CRSP moving into the WALC BA would create organizational and operational concerns. Incurring the cost and organizational stress of moving CRSP into WALC only to move the project into an RTO at a later date would be imprudent.

Moving CRSP into the WALC BA would be challenging. There are significant impacts to:

- Systems
- Processes
- Contracts
- Accounting
- Operations
- Communications
- Metering
- Training
- Operating procedures
- Network infrastructure
- Energy management system
- Interconnected BAs

It would also be a significant impact to human capital across multiple disciplines. It took over three years and dozens of employees to accomplish these same tasks to move the southern portion of CRSP from WALC into the WACM BA. The total costs amounted to approximately $600,000 for labor and $150,000 for capital. The highest costs were associated with contract modifications, settlements, communications, metering, and supervisory control and data acquisition.

Various issues and expenses are associated with maintaining the WACM BA to operate the CRSP system:

- **Contingency reserves:** WACM would have to carry the most severe single contingency for the remaining BAs (two Glen Canyon units) or try to join either the Northwest Power Pool Reserve Sharing Group or the Southwest Reserve Sharing Group. Details would have to be verified and changes to the bylaws and operating agreements of the reserve sharing groups would entail significant work and added expense.
- **Metering complexity**: This would also add metering complexity and expense only to be modified again in a phase-two implementation.
- **Constrained Path Management**: Two of the four qualified constrained paths would remain with the BA. This would require operations staff to manage.

- **NERC compliance**: WAPA would still be required to maintain North American Electric Reliability Council (NERC) registration as a BA and transmission service provider for WACM.
- **Tariff and 10-year planning:** CRSP, LAP and other Mountain West participants have overlapping system elements that interconnect. The CRSP system extends well into the Northern Colorado area and links to LAP and other Mountain West participant's transmission elements. The CRSP and LAP systems would be in two separate tariffs, which would create an administrative burden to manage the upgrades of CRSP, LAP and Mountain West separately. This would more importantly create cost allocation issues.
- **Organization of Operations, EMMO and Settlements:** If CRSP and LAP do not simultaneously join an RTO, then the organizational efficiency of Operations, Energy Management and Marketing Offices (EMMOs) and Settlements would be impaired. WAPA would have to continue to operate much the same as it does today for CRSP while also operating LAP in an RTO. This presents challenges due to workload increasing rather than fully realizing the benefits of common business practices that result in a decrease to workload. There will likely be a loss of most bilateral trading partners to the north of the CRSP transmission system, where the lowest cost energy purchase transactions take place today. Alternatively, drive-out costs to purchase from the newly established SPP market in the West would be incurred. Drive-out costs from purchasing today out of the existing SPP market in the East are approximately $10 per megawatt-hour during the on-peak hours. With growing EIM participation in the Desert Southwest region, loss of real-time trading partners in the Southern market is likely as well.

Due to the factors identified above, it was determined that either both projects could join SPP or neither could.

6. Mountain West analyses performed

Mountain West performed extensive analyses to evaluate the potential benefits and risks of RTO membership. CRSP and LAP then performed more in-depth analyses of the financial and qualitative implications for the projects. This section includes what Mountain West as a group performed. The more in-depth discussions of the CRSP and LAP recommendations are included in sections 7, 8 and 9. The Mountain West analyses included:

- Transmission cost
- Production cost study
- Evaluation of proposals from RTOs
- DC Tie benefits evaluation

Analyses were conducted by:

- The Brattle Group[13]
- Argonne National Laboratory[14]
- The Glarus Group[15]

6.1 Transmission cost analyses

In July 2013, three of the Mountain West participants—Tri-State, PSCO and WAPA—began initial analysis of a joint tariff, specifically analyzing a postage-stamp and rudimentary zonal structure. After expanding the group to additional entities, they engaged a consultant in the summer of 2014 to evaluate potential common tariff transmission pricing structures, evaluate potential cost shifts and develop a method to mitigate those cost shifts. After the consultant's analysis was complete in mid-2015, the Mountain West participants continued to request information from existing RTOs and dive deeper into the specifics regarding the cost shifts resulting from initial zonal constructs. These transmission cost studies resulted in the following preliminary design proposal:

- The Mountain West footprint will be divided into eight pricing zones.
- Network customers will pay the zonal rate in which their load sinks.
- A single postage stamp regional through and out rate (RTOR) will be applied to point to point transmission sales for load outside the SPP footprint.
  - Harmful cost shifts would be mitigated using RTOR revenue for the initial seven years.
  - Revenues will be allocated based on a formula using annual transmission revenue requirement and megawatt-mile flows, after the mitigation mentioned above.

6.2 Mountain West production cost benefits analyses

Based upon the initial analysis from the work done in 2015, Mountain West initiated a production cost study[16] in March 2016 with the Brattle Group Consulting firm. A detailed

[13] "Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint," available at https://www.wapa.gov/About/keytopics/Documents/mountain-west-brattle-report.pdf
[14] "Mountain West Joint Tariff and Regional Transmission Organization Market Study," available at https://www.wapa.gov/About/keytopics/Documents/LAP-CRSP_Production-Cost-Study.pdf
[15] "Mountain West Transmission Group – Southwest Power Pool DC Intertie Value Study," available at https://www.wapa.gov/About/keytopics/Documents/mountain-west-spp-dc-intertie-value-study.pdf
[16] "Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint," available at https://www.wapa.gov/About/keytopics/Documents/mountain-west-brattle-report.pdf

analysis of the potential production cost savings was performed on two constructs: a common tariff only and a common tariff with full RTO market participation.

Results of the analysis indicate that RTO membership has the potential to provide greater benefits than a common tariff alone. As a result of that projected outcome, Mountain West narrowed its focus in early 2016 to further evaluate potential RTO membership.

The estimated aggregate production cost savings from the 2016 and 2024 studies for the Mountain West footprint are shown below in millions of dollars per year. The results shown assume current trends in load growth, natural gas prices, inflation and so on. Confidential individual entity results were prepared for each Mountain West participant.

Aggregate production cost savings	Annual Benefits 2016 (millions per year)	Annual Benefits 2024 (millions per year)
Single tariff/ existing bilateral market	\$14	Not Studied
Single tariff/ RTO Day-2 market	\$53	\$71

There are significant additional savings not included in the Brattle Group analysis. Among other things, RTO markets bring additional savings for real-time dispatch optimization of energy and ancillary services as well as planning reserve margin reductions. These savings are not reflected in the studies Mountain West commissioned. It should be noted that the Brattle Group study analyzed the Mountain West footprint with no connections or ties to the existing SPP market.

6.3 Evaluation of proposals from RTOs

In May 2016, Mountain West issued a request for information (RFI) for an RTO to provide services ranging from common tariff administration to full RTO membership. The RFI was delivered to CAISO, MISO, PJM and SPP. Responses to the RFI were received in July 2016. The range of RTO costs to provide tariff administration or full RTO membership are shown below.

RTO costs	Startup cost from RTO (in millions)	Annual cost (in millions)
Tariff administration only	\$4-7	\$3-7
RTO membership	NA[17]	\$24-60

[17] Startup costs for the RTO to incorporate the Mountain West participants into the membership are included in the annual cost.

6.4 DC tie evaluation

Four of the seven DC ties between the Eastern Interconnection and the Western Interconnection within the U.S. are owned and operated by Mountain West participants. The combined transfer capability of the Rapid City, Stegall, Sidney and Lamar ties is 720 megawatts (MW).

Mountain West and SPP retained the Glarus Group to evaluate the potential benefits of using the DC ties in the market. The study compared the current scheduling process to an alternative process of optimizing scheduled DC tie flows through the market. Additionally, the report considers six scenarios to evaluate benefits under various conditions, specifically: low and high gas prices, low and high loads, and low and high DC tie availability.

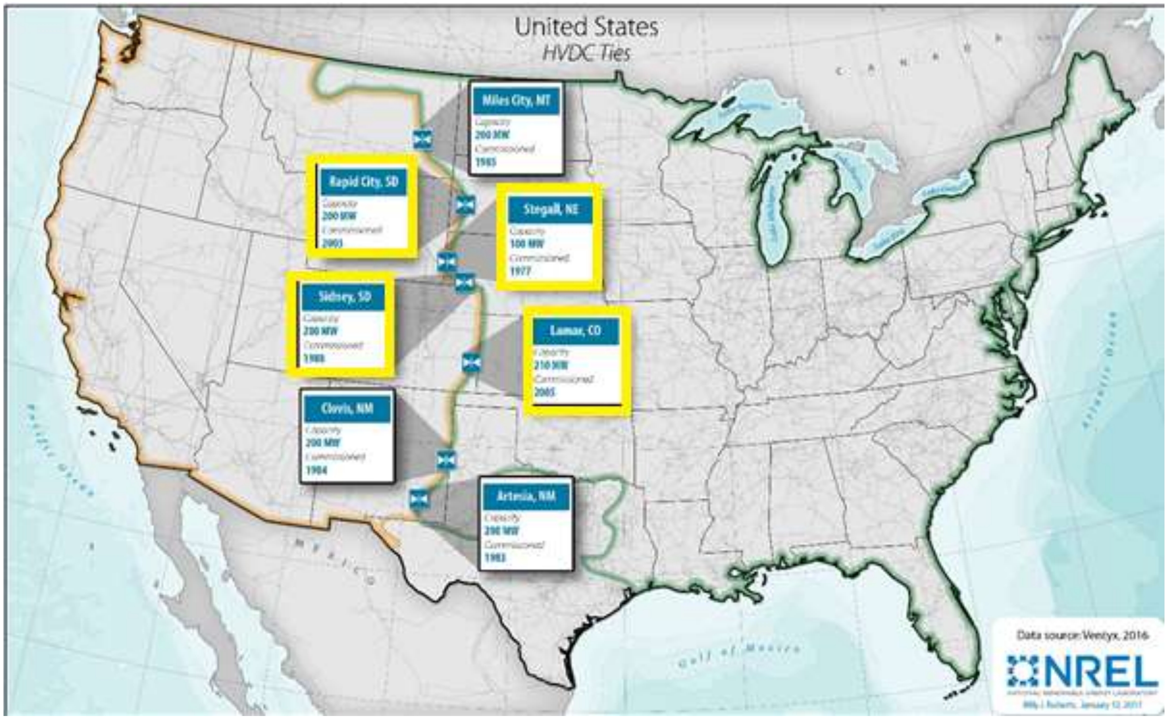
Mountain West and SPP net production cost savings (in millions) between base and alternative cases			
Input parameter	**Low**	**Medium**	**High**
Natural gas price	$13.6	$12.9	$28.8
DC Tie availability	$11.7	$12.9	$12.6
Weather-base load	$14.2	$12.9	$13.2

The results of this study show a significant level of benefits of the SPP market scheduling flow for the four DC ties in the alternative case. If the combined Mountain West-SPP market optimized scheduling of the DC ties, both Mountain West and SPP would see benefits ranging from $11.7 million to $28.8 million, depending upon the key variables.[18]

To summarize the results above it should be recognized that the cost shifts associated from transmission allocation with a joint tariff provide no net economic benefit other than a reduction in pancaked rates to Mountain West as the revenue requirement for the various transmission systems remains the same and must be recovered. While specific transmission cost shifts for CRSP and LAP are discussed in more detail in sections 8 and 9, the total combined benefits to Mountain West from the Brattle Group analysis and the DC tie study range from $25.7 million to $99.8 million while the costs for full RTO membership range from $24 million to $60 million.

[18] "Mountain West Transmission Group – Southwest Power Pool DC Intertie Value Study," available at https://www.wapa.gov/About/keytopics/Pages/Mountain-West-Transmission-Group.aspx

Figure 3: Unites States DC Ties



7. CRSP and LAP-specific financial market analyses

In tandem with Mountain West analyses, CRSP and LAP performed significantly more detailed financial and qualitative evaluations of the implications for the projects. First, Argonne National Laboratory performed a review and deeper evaluation of the confidential CRSP and LAP results from the Brattle Group Mountain West production cost study. Those results are included below and are followed by separate sections for CRSP and LAP.

7.1 CRSP and LAP production cost benefits analyses

7.1.1 Brattle Study

Due to the confidential nature of the model inputs and results, the Brattle Group report only discusses aggregate outcomes without revealing the specific impacts on individual Mountain West entities. The Brattle Group did however compute the following financial estimates for CRSP and LAP for a narrow set of situations:

Scenario	LAP (in millions)	CRSP (in millions)	Mountain West Total (in millions)
2016 Joint Tariff Only	$0.6	$1.1	$14
2016 Market Case	$1.2	$1.4	$88
2016 Must Run Case	$1.5	$2.6	$53
2024 Current Trends	$1.5	$0.5	$71
2024 High Natural Gas Price	$2.2	$1.0	$126
2024 Market Stress	$2.2	$2.6	$128

7.1.2 Argonne National Laboratory Study

As part of a DOE intra-agency agreement between WAPA and the Argonne National Laboratory, Argonne expanded the analyses to estimate the financial implications for CRSP and LAP under a broad set of conditions if the projects participated in a market along with other Mountain West participants.

The Argonne National Laboratory report discusses the estimated financial benefits for CRSP and LAP participation in a joint tariff or RTO with Mountain West.[19]

Argonne National Laboratory estimated the financial impacts of CRSP and LAP operating in a market via a comparative analysis, in which model runs were conducted under two different market frameworks in the year 2024. The first market framework, referred to as the Status Quo case, assumes that all participants continue operations with bilateral market transactions just as today. The second market framework, referred to as the Regional Market, assumes that a centralized wholesale RTO market structure will be adopted by Mountain West under which all participants would always offer all of their operable generating facilities to the market. This comparative analysis quantifies CRSP and LAP financial impacts as the difference between the regional market case and the status quo case.

Separate financial analyses were conducted under three different plausible futures defined by the Brattle Group. The futures used by Argonne National Laboratory for financial analyses include:

- **Current trends (CT):** based on current most likely projections of the future based on a continuation of recent trends
- **High gas (HG):** 2024 natural gas prices assumed to be significantly more expensive than the CT case

[19] "Mountain West Joint Tariff and Regional Transmission Organization Market Study: LAP and CRSP Financial Analyses," available at https://www.wapa.gov/About/keytopics/Documents/LAP-CRSP_Production-Cost-Study.pdf

- **Market stress (MS):** includes high natural gas prices, higher Mountain West regional loads and lower WAPA hydropower generation

For consistency with the Brattle Group study, Argonne National Laboratory utilized key hourly results for the year 2024. To estimate changes in WAPA's financial positions, Argonne National Laboratory calculations rely on Brattle Group locational marginal price (LMP) results that are comprised of three additive components: energy, referred to as the marginal energy component; congestion, referred to as the marginal congestion component; and marginal losses, referred to as the marginal loss component. Unless a specific component is referenced, LMP in this report refers to the total of the three aforementioned components.

7.1.3 LAP Results

For the LAP reference point model run, the annual 2024 financial benefits of joining a regional market were $0.51, $0.20 and $0.06 million for the CT, HG and MS futures, respectively. This reference point is based on average hydropower conditions for the CT and HG futures and dry conditions for the MS future. A second estimate of CT financial benefits was also computed based on an improved pumped storage methodology and more accurate transmission loss accounting. This second estimate decreased CT reference point benefits from the aforementioned level of $0.51 million to $0.16 million. Because it was judged that the revised methodology did not appreciably change analysis conclusions, revised model runs for the two other futures were not performed.

Total LAP benefits ranged considerably depending on the specific assumptions made. A graphical representation of the numerous scenarios modeled is fully described and can be observed in the Argonne National Laboratory report.[20] The average annual benefit of the model runs is about $1 million.

In addition, it is projected that under the CT future, LAP will gain $1.43 million in annual benefits because ancillary service duties at the Yellowtail power plant would not be required under the regional market. Although not computed, higher energy prices at Yellowtail under the HG and MS futures would most likely result in higher benefits.

7.1.4 CRSP Results

Financial estimates for CRSP were based on 105 hydrological outcomes for calendar year 2024. The annual average financial benefits of a regional RTO market for energy production were average -$0.74, -$1.15 and -$2.86 million for the CT, HG and MS futures respectively. Most hydrological conditions yielded a negative or harmful result; that is, 63% of the hydrology

[20] Page 33 of "Mountain West Joint Tariff and Regional Transmission Organization Market Study: RMR and CRSP Financial Analyses," available at https://www.wapa.gov/About/keytopics/Pages/Mountain-West-Transmission-Group.aspx

conditions had negative benefits for the CT and HG futures and 82% of the hydrology conditions had a negative benefit for the MS future. Financial outcomes over all hydrological conditions ranged from -$9.22 to $10.95 million for the CT future, -$12.52 to $18.26 million for the HG future and -$9.033 to $11.93 million for the MS future.

In addition to regional market energy benefits, Argonne National Laboratory also analyzed the financial implications to CRSP of maintaining several grandfathered agreement (GFA) transmission contracts and the Salt River Project Exchange Agreement (SRP Exchange). These agreements will likely need to be maintained by CRSP in a market environment, so it was important to estimate the financial implications associated with each. This analysis is discussed in more detail in section 8.

In general, the Argonne National Laboratory analysis shows that the financial implications to CRSP from participating in a market are highly dependent on the hydrological conditions. When the hydrological conditions are good and the CRSP generation is greater than 5.2 terawatt hours (TWh) per year, CRSP sees less benefit from a market than it would in a bilateral market. This is driven by the fact that when CRSP has excess energy and is selling into the market, it does so at a lower price than it would receive in a bilateral market. Conversely, when hydrological conditions are poor and the CRSP generation is less than 5.2 TWh per year, CRSP sees more benefit than it would in a bilateral market. This is driven by the fact that when CRSP is short on energy it can purchase energy from the market at a lower price than it would in a bilateral market. For perspective, the Salt Lake City Area Integrated Projects averaged 5.283 TWh per year from 2007 to 2016.

8. Financial impact to CRSP

As the focus of Mountain West began to coalesce around joining a RTO instead of creating a joint tariff, CRSP began to narrow its analysis on what the financial impacts will be to CRSP. The cost benefit analysis CRSP developed since the focus shifted to joining an RTO looks at many different aspects. CRSP has attempted to estimate and capture all foreseeable costs and benefits to which it will be subject if it joins SPP.

As CRSP developed and refined its analysis, it identified some challenges to participating in a market. First CRSP determined it would initially incur additional costs from several different areas including RTO costs, increased transmission costs, loss of revenue and information technology/metering costs. CRSP also has some unique challenges that the other Mountain West participants do not. Much of the CRSP firm electric service (FES) load is outside of the Mountain West footprint and this has posed some additional challenges to determining the possible effects to CRSP of joining SPP. Also, CRSP has some unique aspects of its operations which have posed a challenge when determining how they can and should be handled in the SPP environment.

CRSP has been working with the other Mountain West participants to develop a cost shift mitigation agreement to address the challenges and reduce the financial impacts to CRSP. Since the Mountain West discussions began, CRSP's position has been that it would be unable to participate in this initiative unless there were no adverse impacts to the FES rate. With the mitigation agreement that has been developed amongst the Mountain West participants, CRSP believes it will be able to avoid such adverse impacts. CRSP has determined that the projected benefits will outweigh the initial costs and it will be able to successfully mitigate the initial costs.

8.1 Initial financial impact

CRSP estimates the initial financial impact to CRSP will be approximately $9 million to $11 million per year. Under the mitigation agreement this amount will be fully mitigated. CRSP anticipates that by the time the mitigation period ends, the market footprint may expand to include more of CRSP's FES loads and it will realize additional financial benefit that it would not see initially. This includes a reduction in transmission purchases, the ability to leverage CRSP resources more effectively and insulation from poor hydrology.

8.1.1 Market benefits

As described in section 7, WAPA participated in the Brattle Group study and commissioned the Argonne National Laboratory analysis outlined above. For CRSP the results varied slightly between the two studies, but the results of both showed that any benefit would be relatively minimal at best and possibly detrimental under varying hydrologic conditions.

The Brattle Group study looked at the adjusted production cost (APC) savings from market operations under several scenarios. It looked at market operations using 2016 models and 2024 models under several different scenarios. Under the 2016 analysis, the Brattle Group study looked at the APC associated with operating in a joint tariff, a market with coal units modeled as they run today and a market with coal units modeled with additional flexibility. The scenarios analyzed using the 2024 model were current trends, high gas and market stress.

The APC savings shown in the 2016 model Brattle Group study are shown below:

Scenario	APC savings (in millions)
Joint tariff	$1.11
Flexible coal	$1.36
Coal must run (operate as today)	$2.62

In the Brattle Group analysis, these savings are largely generated because in the model CRSP is able to make purchases at a cheaper price than it would be able to in a bilateral market.

The APC savings shown in the 2024 model Brattle Group study are shown below:

Scenario	APC Savings (in millions)
Current Trends	$0.48
High Gas	$1.02
Market Stress	$2.63

As with the 2016 model, the APC savings generated in the 2024 model stem from CRSP's ability to make purchases at a cheaper price than it would be able to in a bilateral market under the various scenarios.

Although the Brattle Group study showed a small benefit to CRSP from market operations, CRSP needed additional analysis of their operations. To get more WAPA-specific data, WAPA contracted with Argonne National Laboratory to provide a more in-depth analysis of the impact of market operations to CRSP.

WAPA requested that Argonne National Laboratory focus its analysis on future-year scenarios. Therefore the Argonne National Laboratory analysis utilized the 2024 data and looked at the same three futures that Brattle Group analyzed: current trends, high gas and market stress. Argonne National Laboratory used the same key Power System Optimizer grid simulations for 2024 that the Brattle Group used. Argonne National Laboratory calculations rely on the Brattle Group LMP results and therefore some of the assumptions the Brattle Group used are also inherent in the Argonne National Laboratory analysis.

For CRSP, the Argonne National Laboratory analysis used several different modeling tools to estimate the amount of seasonal and monthly capacity and energy that would be offered to the FES customers as well as to calculate the financial implications associated with the Salt Lake City Area Integrated Project facilities. The modeling conducted by Argonne National Laboratory utilized 105 different hydrological traces to determine the monthly and annual financial implications to CRSP from its participation in a market. As a secondary analysis, CRSP also asked Argonne National Laboratory to provide an estimate of the financial implications of maintaining the SRP Exchange and the GFAs that CRSP will be required to maintain in a market. The costs and benefits associated with the SRP Exchange and GFA will be discussed in more detail below.

Although the Argonne National Laboratory analysis is similar to the Brattle Group study in that they both analyze APC savings, the Argonne National Laboratory study included additional operational considerations specific to CRSP and provided a more focused estimate of the impacts of market operations. The Argonne National Laboratory study accounts for changes in hydrology whereas the Brattle Group study utilized a static schedule for CRSP. The Argonne National Laboratory analysis also differed from the Brattle Group study in that it took into account the environmental operating restrictions, maximized the financial value of Salt Lake City Area Integrated Project resources in observance of established scheduling requirements and deadlines and looked at market operations under a large sample of hydrological conditions.

The results from the Argonne National Laboratory analysis show a wide range of financial impacts to CRSP from market operations depending on the hydrological conditions. The analysis shows that under the 105 hydrological traces in the current trends scenario, the impacts range from a $10.9 million benefit to a $9.2 million loss. The average annual financial outcome for CRSP over the 105 traces is a loss of $0.74 million. In general, the Argonne National Laboratory analysis shows that when the hydrological conditions are good and generation is above 5.2 TWh, CRSP would sell incidental surplus energy into the market, but at a lower price than it would in the bilateral market. In this scenario, CRSP receives less revenue from selling its energy than it would in a bilateral market. However, because the energy in the market is cheaper, CRSP sees a benefit when it needs to purchase, such as in situations of less than 5.2 TWh in generation, because it can do so at a lower cost than in a bilateral market.

Although both the Argonne National Laboratory analysis and the Brattle Group study show a wide range of financial implications, it should be noted that both of these analyses are models of a market that does not exist today. The results from both studies, as a whole, should be viewed as an indication of possible outcomes rather than as definitive predictions.

8.1.2 Transmission cost changes

In a market environment, CRSP will transition from using point to point reservations to utilizing network service to serve its FES loads. The transition to a network model in market operations has some financial implications for CRSP. This transition will mean that although CRSP will not be required to purchase as much transmission to serve its FES load as it does today, it will be responsible for a greater percentage of the annual transmission revenue requirement. This is due to a loss of third-party transmission customers.

As the entities within the market footprint that are market participants no longer need to purchase transmission from CRSP to serve their load, there will be a reduction in the number of third-party entities purchasing transmission from CRSP. This decrease in transmission purchases will cause a decrease in the denominator of the rate calculation and therefore an increase in the rate. Although the increase in transmission rate is an important aspect of CRSP’s analysis, it is important to consider that this reduction in third parties purchasing transmission from CRSP may occur regardless of its participation in this initiative.

As stated, in a market CRSP will utilize network service for its FES deliveries. This will result in a significant reduction in the amount of transmission CRSP reserves to deliver its FES. Similar to the reduction of third party purchases, this reduction will also cause a decrease in the denominator of the rate calculation causing a corresponding increase in the transmission rate. Ultimately this results in CRSP having to pay a higher rate for each megawatt it needs for its FES deliveries but also not needing to purchase as much. If this transition to network service were not also accompanied by a simultaneous reduction in the third-party entities purchasing transmission, moving to network service for its FES deliveries would be a financial benefit to CRSP.

In the market, CRSP will receive RTOR revenue, which will act as an offsetting revenue in the transmission rate. For the first seven years it is anticipated that the majority of the RTOR revenue will be used for cost shift mitigation, of which CRSP is the primary recipient.

CRSP estimates that the items outlined here will ultimately increase the Colorado River Colorado Missouri (CRCM) transmission rate from $1.48 per kilowatt-month to $3.15 per kilowatt-month. As the footprint expands and additional third-party entities either join the market or discontinue purchasing CRCM transmission, the transmission rate will continue to increase due to the loss of offsetting revenues. It is anticipated that this increase will be offset by the reduction in the amount of transmission CRSP needs to purchase, as well as the receipt of RTOR revenue. Regardless of CRSP's participation in this initiative, this rate increase will occur if entities around CRSP join a market and no longer need to purchase wheeling from CRSP. However, without CRSP being in the market there would not be any corresponding offset.

8.1.3 WACM and ancillary service changes

A transition to SPP's market environment across the Mountain West footprint would include having SPP combine and take over responsibilities for the WACM and PSCO BAAs. With this transition, CRSP would cease to provide ancillary services to the WACM BA and would result in several financial impacts. The estimated impacts in this area include the freeing up of reserve capacity, the loss of reactive supply sales and the reduction of staffing.

Argonne National Laboratory did not analyze the impact that additional reserves would have on CRSP specifically, but SPP has been investigating this in its analysis. SPP has tentatively estimated that, across both the East and West footprints, the reduction in contingency reserve required will likely equate to at least a benefit of $16 million per year. Although CRSP does not have a specific estimate for the benefit it would receive from a reduced contingency reserve requirement, it is likely that CRSP would realize at least some portion of the $16 million SPP has estimated across both the East and West footprints.

CRSP also anticipates that it will realize some net benefit from selling its available regulation in a market. CRSP has 40 MW of regulation available and it estimates that if the 40 MW of regulation clears the day-ahead market it will see approximately $1.1 million in annual revenue. This estimate is based on the amount of revenue that UGP receives for the regulation it provides in the market. Although CRSP will generate approximately $1.1 million in revenue for providing regulation, it estimates that its net benefit will be approximately $654,000 per year. This difference is due to CRSP not receiving the $436,900 of revenue it currently receives from providing regulation.

Another financial impact CRSP anticipates to its ancillary service revenue is a reduction in reactive supply sales revenue under market operations. Today it collects approximately $962,000 in net revenue from reactive supply sales. CRSP estimates that in a market it will only receive approximately $68,000 total, but it would also have to pay SPP approximately $57,000 for reactive supply, therefore the net impact would be a $951,000 per year reduction in revenue. It is worth noting that it is difficult to estimate reactive supply sales as this is a completely new market.

CRSP also anticipates a reduction in staffing cost. Since CRSP shares the cost of personnel for the WACM BA with LAP, it will also see some reduction in cost associated with no longer having to provide BA services.

8.1.4 RTO costs

CRSP anticipates there will be additional financial implications directly associated with operations in an RTO. Some of the items that may have financial implications for CRSP include SPP administrative fees; marginal congestion charges and marginal loss charges associated with exchange agreements and GFAs; miscellaneous market fees; and software system costs.

To soften the initial financial impact of market participation, Mountain West is negotiating a proposed phase-in of the administrative fees. This phase-in still enables the existing SPP members to realize an administrative fee reduction with the new Mountain West members in place. The CRSP cost estimates assume these discounts will be in place for a limited time, but with the mitigation agreement, the costs associated with the SPP administrative fees will be mitigated for the first seven years.

There are three categories of transactions for which CRSP will have to pay administrative fees. CRSP will pay administrative fees for its FES deliveries, required exchange agreements and for the GFAs that it will be required to maintain until expiration. CRSP estimates the administrative fees during the proposed discount period will be approximately $4.5 million per year, and then approximately $5 million per year when the discount expires. Since CRSP is estimating that it will not initially realize any resource-side benefits or transmission benefits from market operations, the increased cost associated with these fees will be mitigated by the mitigation agreement.

As with LAP, CRSP will also have some marginal congestion charges and marginal loss charges associated with firming purchases for its FES deliveries, which are discussed below. Unlike LAP, CRSP will be responsible for the marginal congestion component and marginal loss components for the energy delivered under the transmission reservations it must maintain for its exchange agreements and GFAs.

The SRP Exchange is the largest component of CRSP's exchange agreements. The SRP Exchange was an agreement entered into in 1962 between WAPA and SRP to exchange generation from SRP's Craig and Hayden thermal generators in Colorado with generation from Glen Canyon Dam. This allowed WAPA to serve its load in the North and SRP to serve its load in the South without building additional transmission facilities.

Argonne National Laboratory analyzed the financial impact of maintaining this agreement in a market environment for CRSP. To analyze the financial implications of the SRP Exchange, Argonne National Laboratory analyzed the LMP difference at the points of energy injection and extraction. It then multiplied this difference by the quantity of energy exchanged or wheeled. Argonne National Laboratory estimated the cost of both the wheeling component and exchange component. Argonne National Laboratory estimated that the cost of the exchange portion would be $9.15 million per year and the cost of the wheeling portion would be $4.80 million per year, or $13.95 million per year total.

Although this initially appears to be a significant cost, under market operations in SPP, CRSP would receive annual auction revenue rights that can be converted to transmission congestion rights for the transmission reservations associated with the SRP Exchange. These financial instruments would be used to mitigate the marginal congestion charges and marginal loss charges. To estimate the effectiveness of these instruments, WAPA's Energy Management and Marketing Office conducted an analysis to determine how much of these costs CRSP would likely be able to mitigate. This analysis showed that CRSP would likely be able to mitigate about 90 percent of the marginal congestion and marginal loss charges of the SRP Exchange. Therefore, CRSP estimates that it will incur $1.39 million per year in additional costs to maintain the SRP Exchange.

The transmission reservations CRSP needs to maintain for the GFAs will also have marginal congestion components and marginal loss components, and Argonne National Laboratory analyzed the financial impact of these agreements. Unlike the SRP Exchange, the Argonne National Laboratory analysis shows the GFAs having a net benefit of $1.56 million. This benefit results from the path of one of the GFAs being counter to the general flow, giving it a negative LMP congestion component. This means that CRSP would be paid because it would relieve congestion.

As with LAP, CRSP anticipates that miscellaneous market fees will not be substantial, but they will be present. To estimate the costs, CRSP asked SPP to provide a list of all the miscellaneous market charges CRSP will be subject to and an average monthly cost or credit associated with each. CRSP then went through each charge and estimated whether or not it would apply to CRSP and, if it did, what the annual charge or credit would be. CRSP estimated that the net cost from miscellaneous market charges would be approximately $2,500 per year. Many of these costs will be dependent on the characteristics of the market in the West when it forms. The estimates provided by SPP may not ultimately be accurate since they are based on the market in the East. Due to this uncertainty, CRSP has increased its estimate for these costs in its analysis to $500,000 to be conservative.

CRSP also anticipates that it will have some software costs associated with moving to a market, but because it is in the process of upgrading its marketing software, only a portion of these costs would be attributable to supporting membership in an RTO. CRSP estimates the software costs directly attributable to RTO membership to be $140,000.

8.2 Long-term financial impact for CRSP

The categories listed above for the initial years of SPP membership contain areas in which certain changes will eventually occur. Mitigation will end after seven years, but RTOR revenues will no longer be withheld from the zones. Additionally, certain staff reductions will also be realized. The estimates recognize these savings will not be realized right away. Offsetting these savings, it is expected that the SPP overhead costs will increase over time, and the proposed phase-in of the full administrative fee will take place.

CRSP anticipates that, given these factors, the long-term financial impact will be significantly better than if it were to avoid joining now only to be forced to join at a later date. At the end of the seven-year mitigation period, CRSP anticipates that the market footprint will likely have expanded, it will have the experience necessary with market operations to maximize the benefit from the CRSP resources, and there will be sufficient RTOR revenue to offset the long-term costs associated with market participation. Additionally, CRSP feels that the benefit from being exempt from regional cost allocation and having access to lower cost resources now and into the future are areas that will ultimately be a financial benefit to CRSP.

If CRSP does not join a market now and markets form around CRSP, it anticipates that it will likely face increased costs and a worse long-term financial impact. If a market forms around CRSP, it will be subjected to the loss of trading partners (as experienced by UGP) and an increased cost to purchase energy. CRSP anticipates this would ultimately force it to join a market, and if this happened it would likely do so without a mitigation agreement and possibly without the FSE. CRSP anticipates that if it does not join this initiative the end result will be the same, but it will be at a much greater cost to CRSP than joining today with the mitigation agreement and FSE.

8.3 Transition costs

The cost to initially transition CRSP to SPP membership includes metering additions and upgrades ($0.67 million) and software system additions (first-year cost $0.14 million). Additional staff time to prepare for and implement the transition will be substantial but done within existing staff budgets. The total initial transition cost is estimated to be approximately $0.81 million, and this should be invested in at some point in the future regardless of WAPA's decision with SPP.

8.3.1 Metering additions and upgrades

Exact metering requirements and necessary additions to operate in SPP's market environment are still being identified and estimated, but early projections suggest that numerous generation sites need metering additions or modifications. Early cost estimates have been around $0.67 million, but project estimates are not complete. Regardless of SPP membership, it is recommended that CRSP upgrade its metering equipment, because its generation metering scheme is less than optimal and it incurs energy imbalance (EI) charges from the WACM BA for generation and load deviations. CRSP has a less-than-optimal generation metering scheme in regard to placement and quality at its generators. Because CRSP incurs energy imbalance charges from the WACM BA for generation and load deviations, it is recommended CRSP upgrade this metering equipment regardless of SPP membership.

8.3.2 Software system additions and upgrades

It is too early to have fully developed settlement and merchant software requirement costs, but experience in UGP suggests that the primary impact will be subscription service costs for additional market software modules that are included in the RTO cost category above. Ongoing subscription costs are estimated to be approximately $0.28 million. CRSP and LAP will share these costs. CRSP will be responsible for $0.14 million (50 percent of the cost) for first-year and subsequent annual subscription years. Software support will be provided by the vendor.

8.3.3 Staff time to prepare for and implement transition

The bulk of the staff time in support of the transition will be performed by existing staff and no financial impacts are expected to occur.

8.4 CRSP cost shift mitigation

During the course of discussions with Mountain West, CRSP has always maintained the position that it would only be able to participate in this initiative if there were no adverse effect on the FES rate or there were benefits that would be realized immediately. As can be seen from the financial impact laid out above, CRSP is estimating an initial cost from entering into market operations and joining SPP.

In order to facilitate CRSP's participation and overcome this initial cost, Mountain West has agreed to provide mitigation to CRSP for seven years. In total, the Mountain West participants will provide approximately $11 million per year in mitigation to CRSP in order for it to participate. Under this agreement, there will be no true-up of the CRSP costs. CRSP will receive this amount regardless of the ultimate financial impact when joining SPP. Due to this, although CRSP will incur some additional risk that its actual costs will be higher than it estimated, CRSP may incur some additional benefit from market participation.

With the mitigation agreement in place, CRSP believes that given the qualitative considerations, the likelihood of regional markets expanding in the West and the overall benefits it will receive in the years following the mitigation period, joining SPP is the best course of action to continue to serve its preference customers effectively now and into the future.

9. Financial impact to LAP

WAPA has estimated the new costs and new benefits of LAP joining SPP with a focus on significant cost changes. The cost benefit estimate for the first seven years recognizes the LAP zone will lack a significant amount of RTOR revenues that would otherwise reduce the LAP zonal transmission rate. RTOR revenues are transmission revenues for load located outside the SPP footprint. The lack of these revenues is due to the proposed Mountain West mitigation arrangement that uses RTOR revenues for the first seven years to mitigate entities that have a harmful transmission cost shift. Estimates for the initial years also recognize that the exemption from regional cost allocation will start at zero and grow slowly as regional projects get approved and built.

For a longer-term outlook, the same factors that influence the initial years have been examined for known changes that will occur. In addition, an increasing value of the proposed FSE has been given consideration for the long-term value proposition of joining SPP.

In addition to financial considerations, non-financial factors have been given significant weight to bring WAPA to propose this recommendation.

9.1 Initial financial impact

The total estimates of new costs and benefits for LAP are near zero during the initial years of joining SPP. The financial impact to LAP is estimated to be primarily due to market benefits, transmission cost changes, WACM and ancillary service changes and RTO costs. Each of these categories is discussed below. Within these categories, the sum of new benefits is estimated to be around $5 million per year, and the sum of new costs or lost revenues is also estimated to be around $5 million per year.

It is important to note that while LAP attempted to be realistic in its analysis, many of these estimates require assumptions and could deviate in either direction.

It is noteworthy that the scales of these new costs and benefits are relatively small compared to the total overall LAP revenues, which total approximately $165 million per year. Also significant is the fact that the Pick-Sloan power repayment study, which drives the LAP rate, requires approximately $10 million of change to move the rate by $0.001, or one tenth of one cent per kilowatt hour.

9.1.1 Market benefits

The two referenced reports describing the production cost modeling analyses have been completed to estimate market benefits for LAP. The Brattle Group study was completed first, and then Argonne National Laboratory was utilized to further evaluate and refine the Brattle Group production cost study results. For LAP, specific attention was given to model benefit sensitivities around several variables: hydrological conditions varying from very wet to very dry, the flexibility of scheduling Mt. Elbert pumped storage plant to optimize benefits in the market, transmission loss rate assumptions, varying bid adjustment factors and the impact of exemption from congestion and marginal loss components for firming purchases.

After eliminating the cases of paying only marginal energy component for firming purchases, which has not been pursued, a reasonable middle assumption benefit of all the scenarios seems to be approximately $1 million. This can be graphically observed in the Argonne National Laboratory report, which shows the various sensitivities in one chart. [21]

9.1.2 Transmission cost changes

Transmission cost changes include: the loss of 28 percent of LAP transmission service due to the elimination of pancaked rates, the addition of Cheyenne's annual transmission revenue requirement to the transmission pricing zone and the removal of $5.2 million of annual transmission revenue requirement of the Sidney DC tie. It should be noted that although adding the Cheyenne revenue requirement to the zone increases the rate, losing the load from the Cheyenne system into a different zone would raise the rate even higher. As part of a broader compromise during zonal design negotiations among Mountain West parties, certain settlement agreement terms were agreed to and factored into the overall transmission cost changes. In sum, LAP projects a benefit of nearly $2 million during the initial years, which is necessary to offset new costs shown below.

9.1.3 WACM and ancillary service changes

A transition to SPP's market environment across the Mountain West footprint would include having SPP combine and take over responsibilities for the WACM and PSCO BAAs. With this transition, LAP would cease to balance for the BAA and LAP would cease to sell ancillary services. Significant cost impacts in this area include the freeing up of reserve capacity (though with revenue loss), the loss of reactive supply sales, the loss of energy imbalance and generator imbalance (EI/GI) penalty revenue and the reduction of staffing.

According to the report by Argonne National Laboratory,[22] the elimination of several reserve requirements to regulate, follow variable energy resources and sell contingency reserves makes that capacity available for LAP and would result in financial benefits. Argonne National Laboratory used the production cost model to estimate this value in the market to be $1.4 million. This value is due to the hydroelectric power being utilized in the energy market. This conclusion is supported by the experience of UGP as SPP's co-optimization typically clears WAPA's hydroelectric power predominately for energy rather than ancillary services. Additional benefits were estimated for downward and upward regulation payments, which are also supported by UGP's SPP market experience. However, those benefits to LAP come at the cost of eliminating the revenue that LAP receives by offering these cost-based services to its customers. After factoring in the loss of revenues and adding market costs to cover LAP needs

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[21] Page 33 of "Mountain West Joint Tariff and Regional Transmission Organization Market Study: RMR and CRSP Financial Analyses," available at https://www.wapa.gov/About/keytopics/Pages/Mountain-West-Transmission-Group.aspx

[22] Page 37-38 of "Mountain West Joint Tariff and Regional Transmission Organization Market Study: LAP and CRSP Financial Analyses," available at https://www.wapa.gov/About/keytopics/Pages/Mountain-West-Transmission-Group.aspx

for regulation and reserves, the estimate is actually a slight increase in costs to LAP for regulation and reserves. Although this at first seems counterintuitive, it would follow that a large, optimized market is able to provide these ancillary service products at a lower cost than LAP has been able to by itself.

The sale of reactive supply follows a similar trajectory. LAP's revenue will decrease if reactive supply is converted to the current practice within SPP. The impact to LAP is estimated to be a cost rather than a benefit due to receiving less revenue. However, Mountain West is discussing reactive supply practices that could be employed in an SPP-west market environment, so this analysis will likely change.

Similarly, WACM would no longer offer EI/GI. Terminating these services with pro forma penalty structures would result in additional lost revenue to LAP.

In total, this category is estimated to cost LAP an additional $1.5 million as compared to present day operations. Although harmful to LAP, it is important to note that this loss of revenue for LAP is actually a decrease in costs to LAP customers who will no longer need EI/GI services, and will have access to less expensive regulating reserves from the market.

9.1.4 RTO costs

RTO costs of significance include SPP administrative fees, miscellaneous market fees and software system costs. Mountain West is negotiating a proposed phase-in of the administrative fees that still enables the existing SPP members to realize an administrative fee reduction when the new Mountain West members join. The cost estimates assume these discounts for a limited time. Miscellaneous market fees are not substantial, but will be present and so a rough estimate based on UGP's experience was made. Necessary subscription-based software system costs were also roughly estimated. In total this category is about $1.5 million of new costs.

9.2 Long-term financial impact

The categories listed above for the initial years of SPP membership contain areas in which certain changes will eventually occur. Settlement arrangements will phase out and RTOR revenues will no longer be withheld from the zones to mitigate harmful cost shifts among Mountain West entities. Further, LAP anticipates certain staff reductions will be possible in a market environment in which LAP no longer runs the WACM BAA, sells ancillary services or offers LAP transmission service under the WAPA tariff. Certain merchant office optimizations will also be realized. The estimates recognize these savings will not be right away. Offsetting these savings, it is expected that the SPP overhead costs will increase over time, and the proposed phase-in of the full administrative fee will take place.

Additional long-term financial impacts to LAP include RTOR revenue distribution discussed below and the FSE benefits discussed in section 10.

9.2.1 RTOR revenue distribution

Mountain West has agreed to initially utilize the SPP-west RTOR revenues for mitigating those transmission owners within Mountain West that have a harmful cost shift. The mitigation needs to offset these costs are significant enough that Mountain West has estimated RTOR revenue will be completely exhausted for this purpose for the first seven years. This means that zones will not receive these as revenue credits. However, after the initial seven-year period, as well as any revenue beyond mitigation agreement amounts during the first seven years, revenues will be distributed based 40 percent on revenue requirement ratios and based 60 percent on a megawatt-mile flow-based impact calculation. Despite significant Mountain West efforts to estimate these revenues, estimates with any degree of certainty have been elusive. Regardless, these revenues will have a downward pressure on the LAP zone rate after the first seven years and possibly before.

In sum, the longer-term cost benefit total is conservatively estimated to be approximately zero, but with increased uncertainty and with FSE and RTOR benefits increasing.

9.3 Transition costs

The cost to initially transition LAP to SPP membership includes: metering additions and upgrades ($1.8 million), software system additions (first-year cost $0.14 million) and additional staff time to prepare for and implement the transition will be substantial but done within existing staff budgets. The total initial transition cost is estimated to be approximately $1.94 million, and this should be invested in at some point in the future regardless of WAPA's decision with SPP.

9.3.1 Metering additions and upgrades

Exact metering requirements and necessary additions to operate in SPP's market environment are still being identified and estimated, but early projections suggest that numerous generation sites need metering additions or modifications. Early cost estimates have been around $1.8 million, but project estimates are not complete. As LAP operates as the financial entity behind the WACM EI/GI services, LAP has been able to accommodate a less than optimal generation meter scheme with regard to placement and quality. LAP has EI/GI accounts for all 21 other entities in the BAA. It does not have an actual EI/GI account for LAP and assumes any EI/GI balances is for LAP. Although running a BAA allows for this, it is not necessarily the optimal utility practice to lack this direct generation measurement. For that reason these additions should probably be made, regardless of WAPA's decision with SPP.

9.3.2 Software system additions and upgrades

It is too early to have fully developed settlement and merchant software requirement costs, but experience in UGP suggests that the primary impact will be subscription service costs for additional market software modules that are included in the RTO cost category above. Ongoing subscription costs are estimated to be approximately $0.28 million. LAP and CRSP will share these costs. LAP will be responsible for $0.14 million (50 percent of the cost for first-year and subsequent annual subscription years). Software support will be provided by the vendor.

9.3.3 Staff time to prepare for and implement transition

The bulk of the staff time in support of the transition will be performed by existing staff and minimal to no financial impacts are expected to occur.

10. CRSP and LAP federal service exemption

SPP has an FSE for UGP. CRSP and LAP are proposing to extend the SPP FSE to CRSP and LAP. The FSE has three components and the costs and benefits of each are discussed below:

1. Exemption from regional cost allocation: This part of the FSE will have no immediate value to CRSP and LAP because no regional cost-allocated projects will have been approved and built. For this reason, no benefit was estimated for the initial years. Over time, however, regional projects will be approved and built, and this exemption will grow in value.

2. Exemption from marginal congestion and marginal losses: The locational marginal pricing methodology in SPP and other RTOs has three components: marginal energy component, marginal congestion component and marginal loss component. The FSE provides an exemption from two of these components, specifically the marginal congestion and marginal loss components. This exemption would only apply to CRSP and LAP hydroelectric power that is bilaterally scheduled to statutory load in the day-ahead market. Firming purchases or real time transactions are not exempt from these components. In recent years, CRSP has purchased about 15 percent of its energy, and so it equates that this exemption will cover about 85 percent of CRSP deliveries. LAP has purchased about 20 percent of its energy, and so it equates that this exemption will cover about 80 percent of LAP deliveries. It should also be noted that the congestion and marginal loss components are not necessarily positive value costs but could be negative costs, and therefore a revenue, as the Argonne National Laboratory analysis showed for the CRSP GFAs. For LAP, the Argonne National Laboratory analysis showed that according to the Brattle Group production cost study, LAP would actually be better off being exposed to these charges due to their predominant negative values[23]. The impact of this exemption was integrated into the Brattle Group and Argonne National Laboratory analyses, and so the market benefit numbers presume the FSE carve out is in place for all but firming purchases. For this reason, no separate benefit or cost was assumed in the initial years. However, over time, conditions assumed in the Brattle

[23] Page 27-29 of "Mountain West Joint Tariff and Regional Transmission Organization Market Study: LAP and CRSP Financial Analyses," available at https://www.wapa.gov/About/keytopics/Pages/Mountain-West-Transmission-Group.aspx

Group production cost modeling will either prove different or change, and the perfect hedge against these potential costs should have value and, if nothing else, at least reduce risk.

In addition to the FSE provisions UGP was granted, CRSP is talking with SPP and Mountain West about implementing several additional FSE provisions that would apply specifically to CRSP operations. Due to the additional requirements for firming purchases and the Western Replacement Power and Customer Displacement Power provisions that were a result of the loss in the Salt Lake City Area Integrated Project resource from the Grand Canyon Protection Act, CRSP will need some additional FSE protection to preserve its requirement to provide these provisions. CRSP, SPP and the Mountain West participants continue to discuss whether or not additional provisions are needed and, if they are, how they will be structured.

11. The Southwest Power Pool

In 2016, Mountain West decided to pursue existing membership in an existing RTO rather than create a new one. The efficiencies gained from joining an existing RTO outweighed the costs and complexity of standing up a new RTO.

WAPA created an ad hoc committee of various representatives from CRSP, LAP and Headquarters to evaluate the four possible ISO/RTO candidates. The group performed a pairwise matrix analysis of CAISO, MISO, PJM and SPP proposals.

SPP was selected by WAPA as the best initial choice by the committee using qualitative and quantitative factors of consideration. SPP was later chosen as best initial choice by the entire Mountain West. In January 2017 the group decided to pursue informal discussions with SPP for the following reasons:

- Adjacent market connected by DC ties had potential market efficiency benefits.
- WAPA, Tri-State, Basin and Xcel already had transmission assets, generation assets and load within the SPP footprint in the Eastern Interconnection.
- The stakeholder driven governance model of SPP was preferred.
- Cultural compatibility.
- SPP’s proven ability to onboard new participants.
- Presence in and satisfaction of non-jurisdictional entities in SPP.

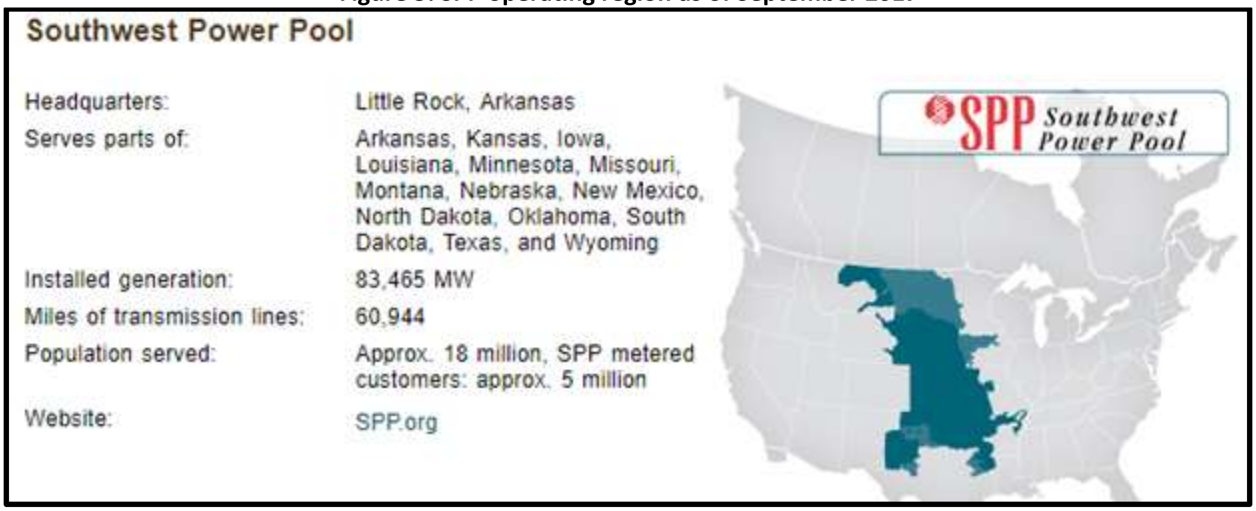
11.1 SPP RTO services

SPP provides the following RTO services to its members:

- Open Access Transmission Tariff Administration and Transmission Service Provider
- Regional Transmission Planner
- Balancing Authority Operator

- Market Operator for Single Integrated Market
  - Day-Ahead Market
  - Real-Time Balancing Market
  - Congestion Market - Transmission Congestion Rights
  - Reliability Unit Commitment
  - Ancillary Services Market
  - Operating Reserve Market
- Market Monitor
- Reliability Coordinator

Figure 5: SPP operating region as of September 2017



12. Additional considerations: reliability coordination and regional reliability entity

The North American Electric Reliability Council requires that each operating entity be a member of both an RC and a regional reliability entity (RE). Peak Reliability is the RC for the Western Interconnection and WECC is the RE. The WAPA regions in the Western Interconnection are Peak Reliability members and WECC members. UGP receives RC services from SPP and is part of the Midwest Reliability Organization RE.

12.1 Reliability coordinator services

As SPP members, the Mountain West participants have the option of maintaining membership in Peak Reliability or transferring to the SPP RC.

CRSP and LAP, along with the other Mountain West participants, have determined that if negotiations with SPP are successful and they move forward with SPP membership, they will have SPP assume the RC functions rather than continue with Peak RC. The decision related to RC services, however, does not impact WAPA's recommendation to pursue final negotiations with SPP. Notably, the entities in Mountain West cover only nine percent of Peak's RC service funding and therefore the increase in cost to the remaining Peak members would be limited.

12.2 WECC remaining as the reliability entity

WECC is a nonprofit corporation that exists to assure a reliable BES in the geographic area known as the Western Interconnection. WECC has been approved by Federal Energy Regulatory Commission (FERC) as the RE for the Western Interconnection. NERC delegates some of its authority to create, monitor and enforce reliability standards to WECC through a delegation agreement.

Figure 6: WECC footprint as the regional entity

WECC has five main program areas they oversee as the NERC-defined RE:

- Compliance monitoring and enforcement
- Reliability planning and performance analysis
- Standards
- Training and education
- Western renewable energy generation information system

WECC also supports stakeholder outreach functions with member-focused committees and user groups. WECC's operating committee advises and makes recommendations to the WECC board on all matters within the jurisdiction of WECC pertaining to maintaining reliability through the operation and security of the BES.[24]

[24] https://www.wecc.biz/Standards/Pages/Default.aspx

Mountain West supports WECC remaining as the RE for the Western Interconnection. NERC and WECC would act as RC certification authorities for SPP to operate as the RC in the Mountain West footprint.

Mountain West envisions approximately one week for an onsite certification process, with an approximate six-month certification preparatory window for SPP.

13. Stakeholder engagement and approval processes

13.1 Stakeholder outreach

Mountain West entities have engaged in over 135 stakeholder outreach sessions in the past three years. These sessions range from meeting with FERC staff to state Public Utility Commission staff, numerous Mountain West participant customer meetings and numerous industry stakeholder forums. Mountain West developed a number of standard update PowerPoint slide decks for all to utilize as needed.

13.1.1 CRSP outreach

- CRSP has provided its customers regular updates at its annual customer meetings, periodic meetings to provide Mountain West updates and when requested by specific customers.
- In addition, similar to LAP, Mountain West has included participation by Tri-State, PRPA, CSU, Intermountain Rural Electric Association and Wyoming Municipal Power Agency which represents a large share of CRSP's allocation of power.
- The Brattle Group study, Argonne National Laboratory analysis, FRN information and more are available at https://www.wapa.gov/About/keytopics/Pages/Mountain-West-Transmission-Group.aspx

13.1.2 LAP outreach

- LAP has regular Loveland Area Customer Association meetings and has briefed customers on an ongoing basis.
- The Mid-West Electric Consumers Association has been regularly updated and has numerous LAP customers within it.
- Mountain West has included participation by Tri-State, PRPA, CSU, IREA, WMPA, Basin and Pre Corp., which represent a majority share of LAP's allocation of power.
- A large number of entities with LAP allocations are on the east side, take their allocation beyond the LAP transmission system and are already within the SPP market. For this reason the West customers have more at stake as it transforms their environment, whereas the East customers are already in the SPP market.

- The Brattle Group study, Argonne National Laboratory analysis, FRN information and more are available at https://www.wapa.gov/About/keytopics/Pages/Mountain-West-Transmission-Group.aspx

13.2 Varying types of approvals required for different entities

There are several types of electric utility entities within Mountain West with differing approval requirements. These entities include investor-owned utilities, cooperatives, municipals and federal entities. As WAPA is a federal power marketing administration, the approval process is specific to legislation and existing federal requirements and is accomplished through the FRN process supported by substantial customer interaction.

13.3 WAPA's Federal Register Notice process

CRSP and LAP will publish an FRN and seek public comment regarding the "Recommendation for the Western Area Power Administration Loveland Area Projects and Colorado River Storage Project to Pursue Final Negotiations Regarding Membership in a Regional Transmission Organization." A 45-day public comment period will be provided upon publication of the FRN. WAPA will present a detailed explanation of the recommendation for LAP and listen to customers' and other interested parties' comments at a forum in Loveland, Colorado. WAPA will also present a detailed explanation of the recommendation for CRSP and listen to customers' and other interested parties' comments at forums held in locations throughout the CRSP marketing area. Any decision to pursue the recommendation will be informed by comments received. CRSP and LAP will publish the decision on WAPA's website and send corresponding letters to customers.

13.4 The SPP stakeholder process

For some Mountain West entities, the proposed membership is contingent upon modifications to governing documents such as the SPP open access transmission tariff (OATT) and Regional State Committee bylaws. SPP has developed specific procedures that are followed to modify these governing documents. The SPP procedures are guided by the overarching need to allow flexibility to deal with unique features of the prospective transmission-owning members throughout the process, while balancing appropriate transparency for member participation and allowing for confidential discussions and negotiations. SPP staff remains solely responsible for the direct negotiations with the prospective members, with input from the stakeholders on both policy and specific changes to the governing documents. When evaluating the overall process of adding new transmission-owning members, the prospective members go through the following five stages:

1. Initial discussions
2. Due diligence and membership agreement discussions
3. SPP OATT and governing document changes
3. FERC approvals

4. Integration

Further information can be found in the document titled, “SPP Task Force on New Members Proposed SPP Stakeholder Communication Process Final Report”[25].

At the time of drafting this report, CRSP and LAP, along with the other Mountain West participants, are engaged in stages 2 and 3 with SPP.

14. Key considerations and conclusions for both WAPA projects regarding SPP membership

Key considerations and conclusions are listed in bullet form below to address negative and positive factors for CRSP and LAP membership in SPP. WAPA understands the nature of such a decision comes with risks and benefits and has worked diligently to cover the broad spectrum of impacts.

Negative factors have been considered and include concerns such as:

- Joining SPP results in the transfer of operational control to another entity, thus giving up discretion and control.
- LAP and CRSP transmission service would be under a jurisdictional tariff, whereas WAPA is non-jurisdictional with a “safe harbor” tariff.
- Joining SPP results in less control over transmission rates and the LAP and CRSP zonal revenue requirement.
- A market environment will increase interest in unbundling LAP and CRSP FES.
- SPP governance requires substantial participation and results in significant hours being spent tracking and participating in a wide scope of operational concerns. FERC proceedings will also require more attention and time investment.
- Joining SPP results in LAP and CRSP being subject to a large group stakeholder process and changes may result with LAP and CRSP having very limited control.
- Although the FSE helps, energy, congestion and ancillary service markets bring a certain degree of cost uncertainty.
- Once integrated with SPP, it would be difficult for LAP and CRSP to separate.
- There will be challenges associated with LAP/Desert Southwest (DSW) region operations consolidation as each region would cover differing responsibilities.

[25] Page 19 of “New Member Cost Allocation Review Process,” available at https://www.spp.org/documents/43938/new%20member%20cost%20allocation%20review%20process%20final%20review%2020161024.pdf

Positive factors include the following:

- Proceeding with joining SPP will enable a west side market to form and optimize resources across an increasing footprint of the Western Interconnection. If WAPA decides not to join, it either prevents or makes it very difficult for a market to form in the near future. Significant regional resource optimization benefits would be prevented from becoming a reality.
- A decision to join SPP transfers control of non-core mission activities such as being a BAA and transmission service provider to the RTO while enabling WAPA's focus to remain on and concentrate its attention on its core mission of marketing and delivering FES to preference customers consistent with sound business principals.
- Mountain West and current negotiations with SPP have been an opportunity for WAPA to direct its own destiny, influence terms and shape the kind of environment desired to ensure WAPA continues to deliver on its core mission activities. A decision to not join SPP would introduce risk and possibly eliminate such future opportunity.
- Joining SPP will avoid a potential greater financial uncertainty of not joining. The costs of losing bilateral trading partners, having to pay drive out fees and a future with potentially less favorable RTO terms will introduce significant increased costs and negative qualitative considerations.
- LAP and CRSP, which provide an average of about 6 percent and 10 percent respectively of total preference customer resource requirements, should not necessarily impede customers from being able to join an RTO if it makes sense for them. Although this decision is very important for WAPA, the broader industry is also moving in the direction of bringing this about and therefore it would not be appropriate for WAPA to prevent a larger industry movement from taking place.
- LAP's Eastern Interconnection customers, as well as SPP members in general, will benefit from SPP expansion, reduction of SPP administrative fees and a larger, more efficient market.
- Enabling a second RTO market in the Western Interconnection increases options for DSW.
- Joining an RTO will enable the optimization of transmission expansion on a broader scale and will allow market-based transmission expansion benefits to be identified and justified.
- Joining SPP will avoid a market potentially forming around LAP and CRSP, bringing significant complexity regarding the WACM BAA, ancillary services, market interaction and the creation of seams.

Mountain West, CRSP and LAP performed extensive evaluations of the potential risks, costs and benefits of SPP membership. While there are some negative factors involved with SPP membership for CRSP and LAP, WAPA believes the positive factors outweigh the negative. Based on both negative and positive factors in addition to the extensive financial analysis in previous sections of this report, WAPA recommends that CRSP and LAP finalize formal negotiations with SPP for full RTO membership.

Appendix: Acronyms

Following is a list of all acronyms and initialisms used throughout this document, along with their definitions.

APC: adjusted production cost
ATC: available transfer capability
BA: balancing authority
BAA: balancing authority area
CAISO: California Independent System Operator
Cheyenne: Cheyenne Light Fuel & Power Company
CRCM: Colorado River Colorado Missouri
CRSP: Colorado River Storage Project
CSU: Colorado Springs Utilities
CT: current trends
DSW: Desert Southwest
LAP: Loveland Area Projects
EI: energy imbalance
EIM: energy imbalance market
EMMO: Energy Management and Marketing Office
FERC: Federal Energy Regulatory Commission
FES: firm electric service
FRN: *Federal Register* notice
FSE: federal service exemption
GFA: grandfathered agreement
GI: generator imbalance
HG: high gas
ISO: Independent System Operator
LMP: locational marginal price
MISO: Mid-Continent Independent System Operator
Mountain West: Mountain West Transmission Group
MS: market stress
MW: megawatts
NERC: North American Electric Reliability Corporation
OATT: open access transmission tariff
PJM: PJM Interconnection, LLC
PRPA: Platte River Power Authority
PSCO: Public Service Company of Colorado
RC: reliability coordinator
RE: reliability entity
RFI: request for information
RM: Rocky Mountain
RTO: Regional Transmission Organization

RTOR: regional through and out rate
SPP: Southwest Power Pool
SRP: Salt River Project
SRP Exchange: Salt River Project exchange agreement
TWh: terawatt hours
UFMP: unscheduled flow mitigation plan
UGP: Upper Great Plains
WACM: Western Area Colorado Missouri
WALC: Western Area Lower Colorado
WAPA: Western Area Power Administration
WECC: Western Electricity Coordinating Council